A SUBMISSION
to
THE ROYAL COMMISSION on ENERGY

SHELL OIL COMPANY OF CANADA, LIMITED

Borden

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SHELL OIL COMPANY OF CANADA, LIMITED

May 1958

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A SUBMISSION TO THE ROYAL COMMISSION ON ENERGY

Introduction

The following Submission is made to The Royal Commission on Energy by Shell Oil Company of Canada, Limited, a company incorporated under the laws of Canada. Shell Oil Company of Canada, Limited is a fully integrated oil company engaged in all phases of the oil business in Canada. Thus it is engaged in the exploration for, and production of, oil and gas, as well as refining, transportation and sale and distribution of petroleum and petroleum products, including the manufacture and sale of petrochemicals.

Shell Oil Company of Canada, Limited is owned 50 percent by Canadian Shell Limited, an Ontario company, and 50 percent by Shell Oil Company, a Delaware corporation. Of the stock of Shell Oil Company 65.32 percent is owned by Canadian Shell Limited, and the balance by the public. Shell Oil Company of Canada, Limited is therefore owned directly and indirectly to the extent of 82½ percent by Canadian Shell Limited, a holding company which conducts no direct operations and which owns the major portion of the investments of the Shell Group of companies in the Western Hemisphere.

Section I

OIL AND GAS EXPLORATION AND PRODUCTION

Shell's Position in the Industry

Shell commenced exploration for oil and gas in Alberta in 1941 and has since that time conducted an intensive exploration and production program in Western Canada.

At the present time our Company has proved reserves in Western Canada of 93 million barrels of crude oil, which is approximately 3 per cent of total proved crude oil reserves, as calculated by the Canadian Petroleum Association. Our 1957 production of crude oil, amounting to 4.7 million barrels, was 2.6 per cent of total Western Canada production.

Our position in respect to reserves and production of natural gas is, however, of a different order. Total production of saleable gas in Alberta during 1957 was 136 billion cubic feet. Of this, our Company sold 17.6 billion cubic feet, or 13 per cent. Our proved reserves of natural gas in Alberta at the end of 1957 totalled 1.2 trillion cubic feet, or approximately 7 per cent of total proved reserves in Alberta as estimated by the Canadian Petroleum Association.

We have observed with interest the proceedings of your Commission. There seem to be few areas of the exploration and production phase of the oil and gas industry that have not been discussed. We have had some difficulty in deciding what aspects of our operations or of the problems of the exploration and production phase of the industry would be of interest and benefit to your Commission.

We do not wish to impose upon the Commission by submitting information which may have already been adequately presented. It has occurred to us that we might make some useful contribution to your consideration of problems relating to oil and natural gas by discussing the extent to which we would expect hydrocarbons will be found in Western Canada and then some of the matters relative to the finding and development of reserves of natural gas.

II. HYDROCARBON — GENERATING CAPABILITY OF THE WESTERN CANADA SEDIMENTARY BASIN

(1) *Introduction*

We would like to discuss, in the first instance, our ideas on how much oil and gas could have been *generated* in the Western Canada sedimentary basin.

In a later section we shall make an estimate of the possible *recoverable* reserves of oil and gas which may be available to us in the basin. This amount is, of course, only a part of the total oil generated.

Any such calculations must start with an estimate of the volume of sedimentary rocks in the basin.

(2) *Calculation of Volume of Sediment*

Basically, this is a simple problem in geometry. The factors which cause one estimate to differ from another are:

(i) Estimation of depth of basement in areas where no boreholes have penetrated the full sedimentary column.

(ii) Assessment of what areas to include in regions which are unexplored. In parts of the Cordillera and in parts of the Yukon and Northwest Territories, the rocks have been subjected to so much heat and pressure that we believe any oil in them would have been driven out. There is some difference of opinion, however, as to where the boundary between normal and altered sediments should be drawn. We have decided which areas to include in our calculations on the basis of a reconnaissance examination of these rocks.

(iii) Arbitrary limitation of basin volumes by eliminating the basin margin or all rocks below a certain depth. We have imposed no such limitation because

(a) the basin margins make up a negligible volume, and

(b) technological advances constantly lower the depth to which drilling operations may be conducted.

The extent of the Western Canada sedimentary basin is shown on Exhibit 1. The commonest method of calculating sedimentary volume is to divide the surface of the basin into measured areas of constant average thickness and multiply out. This is the method we have employed in the Northwest Territories. (See Exhibit 2). But, in the Plains, we varied this method to give an independent check on the published Canadian Petroleum Association figures by dividing the area into three parallel strips, through which ran the 50th, 54th and 58th parallels of lattitude. A geologic profile was constructed along each of these parallels and its cross-sectional area calculated. (See Exhibit 3). The volume was found by multiplying the cross-sectional area by the width of the strip.

The results of our calculations are summarized in Table I. The total sedimentary volume for the normal sediments of the Western Canada Sedimentary Basin is figured at just over one million cubic miles. Our estimates are rather higher than those submitted to the Commission by other witnesses but this is chiefly due to the inclusion of wider areas of the relatively unexplored northern territories.

TABLE I

Area	Volume of Sediments in Cubic Miles
Manitoba and Saskatchewan plains.........	169,800
Alberta and British Columbia plains........	404,000
Alberta folded belt.......................	47,500
British Columbia folded belt...............	54,000
Northwest Territories.....................	242,600
Yukon..................................	142,100
Total..................	1,060,000

(3) *Calculation of Oil Generating Capability*

In round figures then, we have one million cubic miles of sediment. Our next task is to find its oil-generating capability. Our calculations of this factor were based on a study of the published work of John M. Hunt and George W. Jamieson* of the Carter Research Laboratory. Hunt and Jamieson took as a case history the Frontier formation in the Powder River basin of Wyoming. The authors write "It is fairly uniform in thickness, and contains about 900 feet of shale and about 200 feet of sand in the form of sand lenses distributed throughout the formation. Since the sand bodies are completely surrounded by shale, it is probable that the oil in the Wall Creek sands is Frontier in origin. The particular area studies . . . comprised about 800 square miles, including all the major Frontier oil pools in this basin".

The above data show that there is about 460 million acre-feet of Frontier shale present in the Powder River basin.

They calculate the hydrocarbons in the sands within the Frontier formation. "This figure not only includes the oil in the pools, but also an estimate of oil in the sands between the pools, which is unlikely to be much more than one billion barrels. The total of all this

* — "Oil and Organic Matter in Source Rocks of Petroleum", Bulletin of the American Association of Petroleum Geologists, Vol. 40, No. 3 (March, 1956), pp. 477-488.

reservoired hydrocarbon is about 2½ billion barrels . . ." This figure refers, of course, to oil in place, not to recoverable oil.

By dividing this oil volume by the volume of shale, we can see that each acre-foot of shale has fed an average of just over 5 barrels of oil into the Frontier sandstone reservoir.

These authors also chemically analyzed Frontier shale and a number of other shales of different types to find out how much hydrocarbon was still left in the shale. Analysis of the Frontier gave a residual oil content of 6.4 barrels per acre-foot; some of the other shales yielded more, and others less, oil per unit volume.

We believe that the amount of residual oil in a shale is a pretty fair indication of its oil-generating capability and, thus, under equivalent conditions of temperature, pressure and time, of the relative volume of oil that it has given up to the reservoir.

In Hunt and Jamieson's study of the Frontier, the ratio of reservoir oil to residual oil was 5.42:6.4 or 0.85:1. We have assumed for the purposes of this study that this ratio applies to all shales which have not been subjected to abnormal compressive stress.

In order to extend this study to Western Canada, we had to match our formations as closely as possible to the formations which Hunt and Jamieson had analyzed.

The Colorado shales of the Canadian Upper Cretaceous are of the same age and rock type as the Frontier and may be assumed to have similar oil-generating capability. The Mississippian Banff formation of Canada was, fortunately, one of the formations which the authors analyzed. For the other formations in Canada, we chose the nearest analogue we could find in Hunt and Jamieson's work based on our knowledge of the rock types. In the first column of Table II are the main oil-generating formations which we used in our study; in the second column are the analogues which we chose from the work of Hunt and Jamieson; in the third column are these authors' analyses of residual hydrocarbon; and in the last column is our estimate of the oil these sediments have given up to the reservoir — arrived at by multiplying column 3 by the factor of 0.85 discussed earlier.

Table II

Source Formation	Analogue	Bbls/Acre-Ft. of Hydrocarbon Remaining in Source Rock	In Reservoir
Lea Park — Colorado	Frontier	6.4	5.42
Fernie	Springer (Black)	8.0	6.77
Banff	Banff	22.0	18.63
Upper Woodbend	Beekmantown	1.2	1.02
Lower Woodbend — Beaverhill Lake	Phosphoria	11.0	9.31
Cambrian	Beekmantown	1.2	1.02

Ideally, one should next calculate the volume of each type of shale over the entire sedimentary basin. But our knowledge is not yet sufficient for this, nor would the amount of labour involved be justified by the expected gain in accuracy.

What we have done is to make a detailed study of a sample block of sediment located in the geographic center of Alberta (we disregarded all shales buried under less than 3,000 feet of overburden because the oil may not have been expressed from these). The results of this study were then averaged over the whole basin. The block comprised a volume of sediment equal to about one percent of the total volume in the basin. The rocks in it are probably a fair sample of the rocks in the whole basin, being richer in source-rock possibilities than those of Saskatchewan but perhaps poorer than those of the MacKenzie Basin in the Northwest Territories.

Our calculations for the oil generated in the sample block are shown in Table III. We estimate that the shales in this block may have given up nearly 40 billion barrels of oil to the associated reservoirs.

TABLE III

Calculation of oil generated in sample block
Area 3,960 square miles
Average sedimentary thickness 11,162 feet = 2.114 miles
Sedimentary volume 8,371 cubic miles

Source Formation	Thickness	Acre-Feet	Reservoir Oil per Acre-Foot	Reservoir Oil in Millions of Barrels
Lea Park..........	900	2,280,960,000	5.42	12,363
Fernie............	100	253,440,000	6.77	1,715
Banff.............	330	836,352,000	18.63	15,581
Upper Woodbend..	600	1,520,640,000	1.02	1,551
Lower Woodbend — Beaverhill Lake..	300	760,320,000	9.31	7,079
Cambrian.........	200	506,880,000	1.02	517
			Total	38,806

Finally, assuming that our sample block is a fair sample of the Western Canada sedimentary basin as a whole, we conclude that all the sediments in the basin should together be capable of delivering 4½ trillion barrels of oil into the associated reservoirs.

TABLE IV

Calculation of oil in Western Canada Sedimentary Basin by extra-polating from sample block

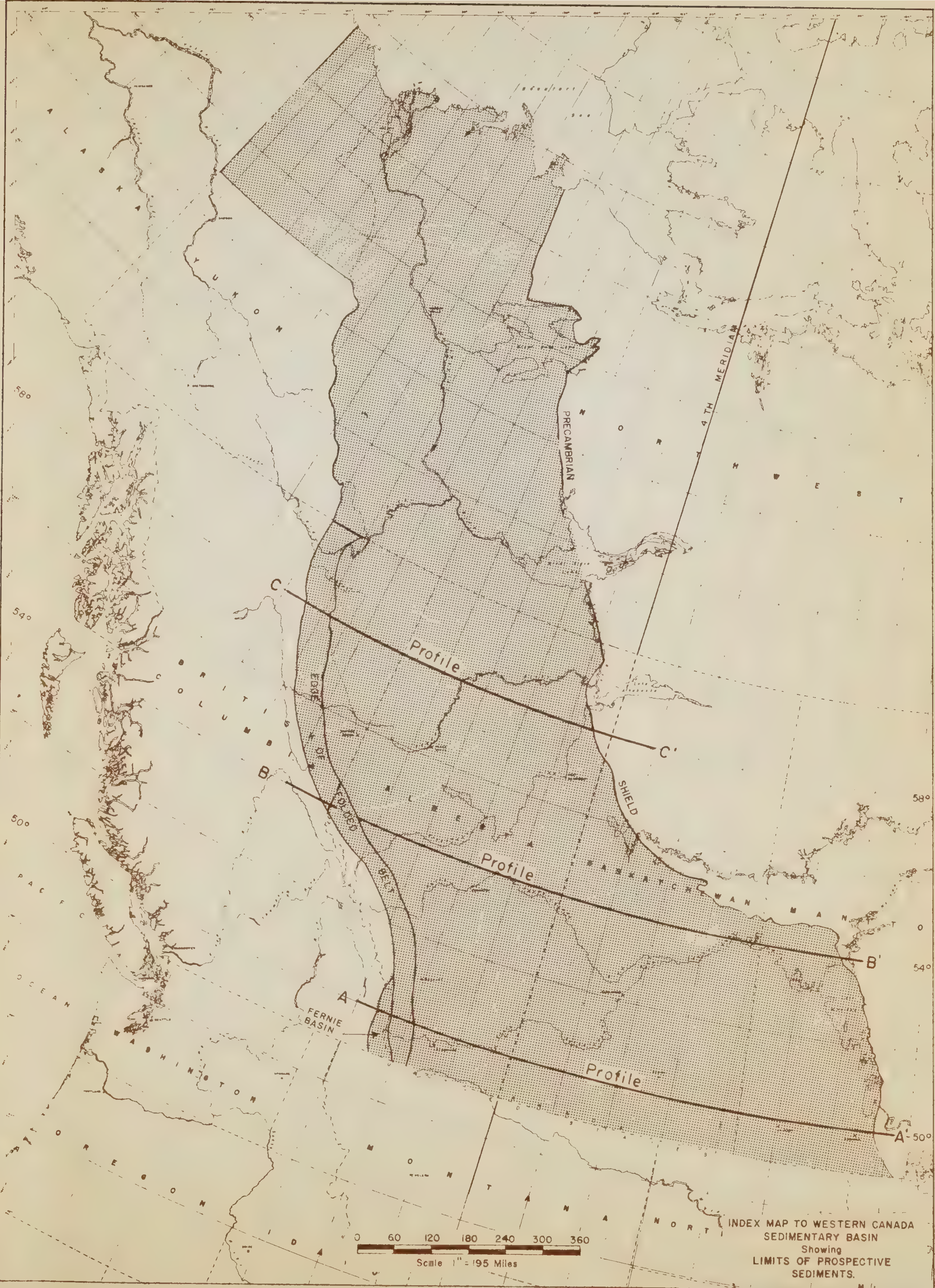
Total volume of sediments (rounded figure)..........................1,000,000 cubic miles

Volume of sediments in sample block... 8,371 cubic miles

Volume of reservoir oil generated in sample block..................... 38,806 million barrels

∴ Volume of reservoir oil generated in total basin

$$\frac{1{,}000{,}000 \times 38{,}806}{8{,}371} = 4{,}636 \text{ billion barrels}$$



INDEX MAP TO WESTERN CANADA
SEDIMENTARY BASIN
Showing
LIMITS OF PROSPECTIVE
SEDIMENTS.
0 60 120 180 240 300 360
Scale 1" = 195 Miles
Profile
C
C'
B
B'
A
A'
FERNIE
BASIN
EDGE OF FOLDED BELT
PRECAMBRIAN
SHIELD
4TH MERIDIAN

EXHIBIT I

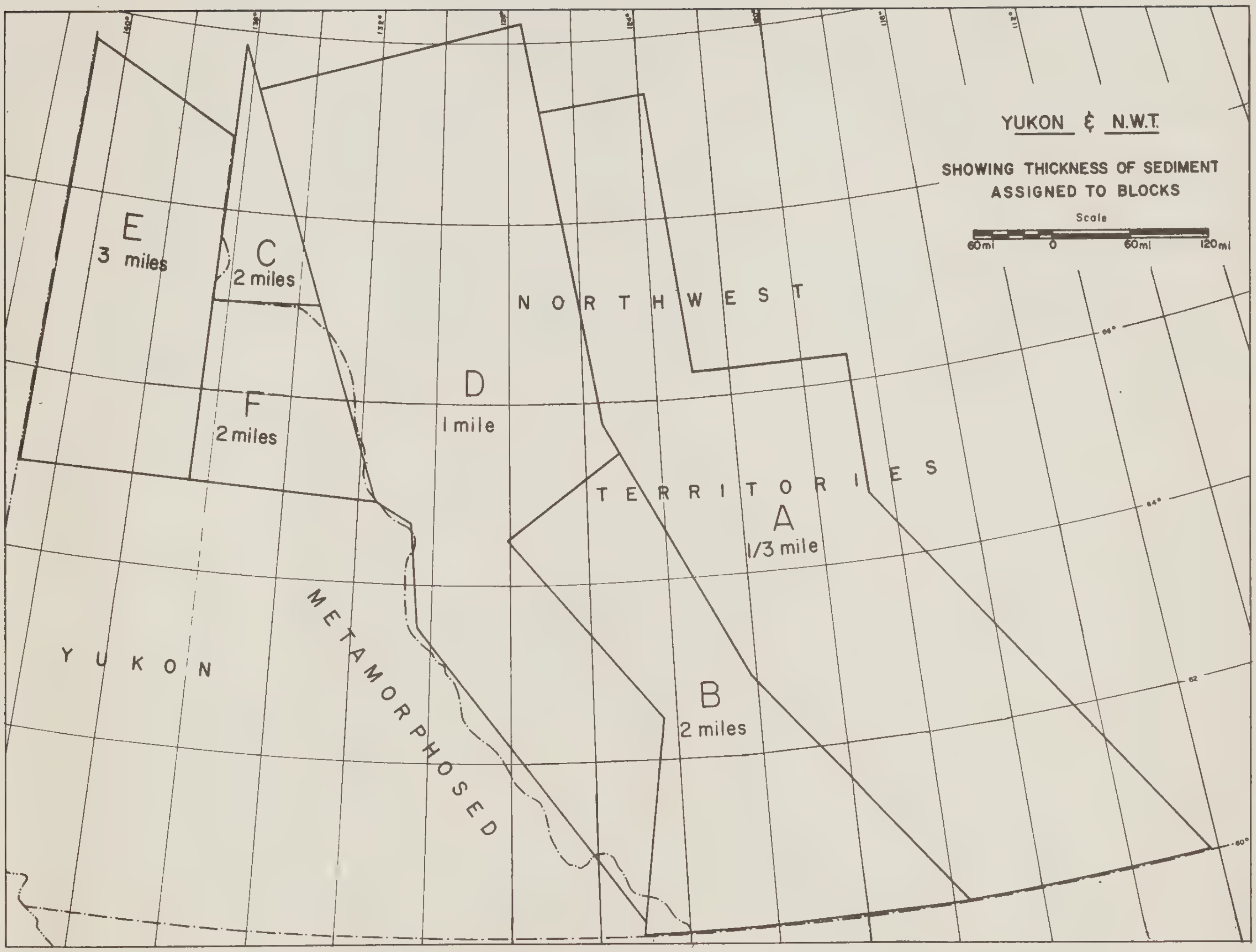
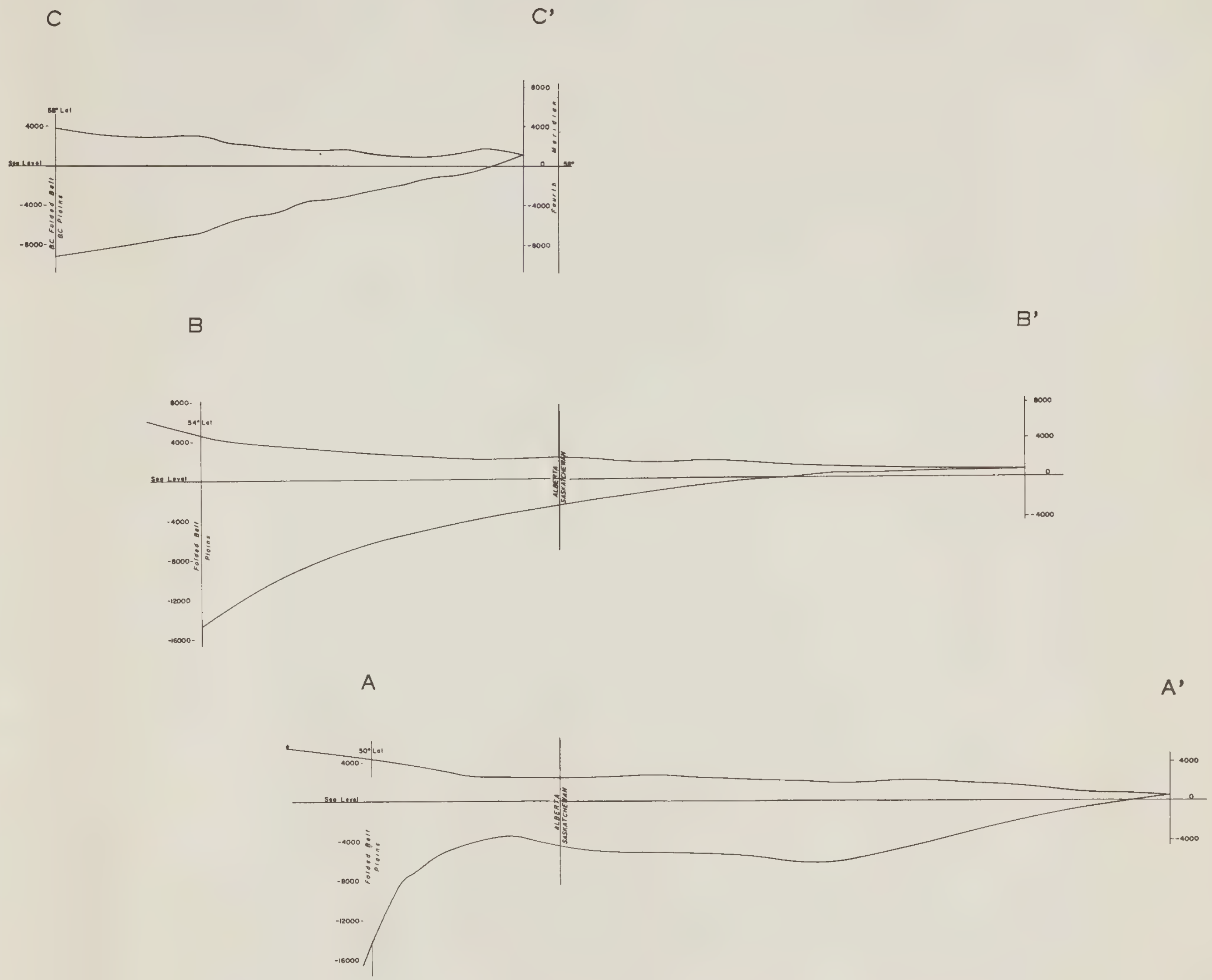

YUKON & N.W.T.
SHOWING THICKNESS OF SEDIMENT ASSIGNED TO BLOCKS
Scale
60mi 0 60mi 120mi
E
3 miles
C
2 miles
F
2 miles
D
1 mile
A
1/3 mile
B
2 miles
NORTHWEST TERRITORIES
YUKON
METAMORPHOSED

EXHIBIT - 2



PROFILES ACROSS WESTERN CANADA SEDIMENTARY BASIN

HORIZONTAL SCALE

0 40 80 120mi

EXHIBIT-3

III. POSSIBLE RECOVERABLE RESERVES OF THE WESTERN CANADIAN BASIN

The foregoing approach has attempted to demonstrate by *geochemical* reasoning, how much oil has been generated in the Western Canadian sedimentary basin. We would now like to show on the basis of *analogy* with a neighbouring sedimentary area, how much of this oil might be found and recovered by the oil industry.

Some idea as to the quantity of undiscovered reserves may be gained by an understanding of the geological conditions which control their occurrence. In areas of similar geological history, the unexplored regions may reasonably be expected to contain an amount of petroleum per unit volume of sediments comparable to what has been found in the sediments of the explored regions.

We observe that the Western Canadian sedimentary basin is a northwesterly extension of the Interior Plains of the United States with similar rock formations and geological history. The United States portion of this vast area has been densely explored and a substantial portion of the possible ultimate has been discovered.

The proved virgin reserves [1] of the United States are estimated by the American Petroleum Institute to be 94 billion barrels as of January 1, 1958. The volume of effective sediments of the United States has been calculated by L. G. Weeks [2] and others to be two million cubic miles. The proved oil reserves per cubic mile of sediments are, therefore, 47,000 barrels. Applying this factor to the one million cubic miles of sediments we estimate to be in Western Canada, gives a possible ultimate recovery of approximately 50 billion barrels.

Up to the end of 1957, the industry has found in Western Canada more than 6,000 cubic feet of gas for every barrel of crude oil. We have reason to believe that this ratio will increase in the future with increasing direct exploration for gas (e.g. in the United States the ratio increased from 4,700 cubic feet per barrel of oil in 1950 to an average of about 8,000 cubic feet per barrel of oil for the last 3 years). Applying the low ratio of 6,000 cubic feet per barrel, Western Canada's ultimate gas reserves would be 300 trillion cubic feet.

[1] — Virgin reserves are defined as the sum of cumulative production and proved recoverable reserves.
[2] — A. A. P. G. Bulletin, Vol. 34, No. 10.

We thus endorse the estimates of the Canadian Petroleum Association. However, we have based our estimates on the already proved reserves of the United States and as exploration continues, further large additions to reserves may be expected to be found there. Therefore, we should stress that we regard our estimates for Western Canada as minimum values.

Our estimate of 50 billion barrels plus that of the Athabasca reserves of 200 billion barrels, is apparently only 5 per cent of the generative capability of the basin. These figures give us a feeling of confidence that our reserve estimates are well within the right order of magnitude.

IV. SHELL'S COMMENTS ON CONSERVATION BOARD GAS RESERVE ESTIMATES

We list below a comparison of the Conservation Board's estimate and Shell's estimates of our own gas reserves. Since Shell's reserves, as such, are not given by the Conservation Board we have taken the liberty of assessing our share of the reserves from the individual field totals. The Conservation Board estimates are believed to be roughly equivalent to proved reserves (calculated by American Gas Association Rules) plus 50% of the probable reserves and we have used the same weighting for our own estimates.

TABLE V

SHELL'S NON-ASSOCIATED GAS RESERVES

(Proved plus 50% Probable)

Field	Conservation Board Field Total Estimate	Shell's Percentage of Field Total	Shell's Reserves Conserv. Board Estimate	Shell's Reserves Shell's Own Estimate
Carbon	203	30%	61 Bcf	90 Bcf
Crossfield	150	70%	105	195
Homeglen-Rimbey	770	10%	77	113
Jumping Pound	518	100%	518	580
Okotoks	135	15% of 78%	16	17
Olds	60	100%	60	258
Sarcee	150	84%	126	215
Waterton	700	70%	490	590
Whitelaw	68	50%	34	34
			1487	2092

The difference between the two estimates is in the amount assigned to probable reserves. Probable reserves are reserves that have not been proved by drilling but are based on geological or geophysical data and interpretations which are not common knowledge in the industry. It has been our experience that a prudent evaluator will always make a low estimate of probable reserves if he lacks the necessary information and we believe that the low estimates of the Conservation Board substantiate this experience. We have concluded, on the basis of fields in which Shell operates, that the Conservation Board figures are low and that, when the presently known fields in the Province have been more clearly defined by drilling, their reserves will be substantially higher than the Board now estimates.

V. SHELL'S VIEWS ON GROWTH OF GAS RESERVES IN FOOTHILLS BELT

In Western Canada, the discovery of most of the gas reserves has been incidental to the search of oil and, hence, it is difficult to predict the increase in gas reserves if the industry put forth a concerted effort towards exploration for gas.

Numerous other briefs have been presented to the Commission showing the growth trend of gas reserves for the Western Canada sedimentary basin as a whole. We would like to present the results of our study of an area in which we are most active, namely the Foothills Belt of Alberta (see Exhibit 4). This belt contains 2 percent of the total area and 4.5 percent of the total sediments of Western Canadian basin.

Four of the nine gas discoveries made in the Foothills Belt since 1944 are presently in various stages of field development. (Jumping Pound, Pincher Creek, Savanna Creek, Waterton). After the drilling of each discovery well, the Conservation Board credited to the discovery, the reserves underlying some 1,000 acres. This set the total reserves of the four fields at 300 billion cubic feet initially. The ultimate recovery of these fields is now carried by the Board at 3,500 billion cubic feet as a result of the development

to date; therefore, it is readily apparent that development has increased the credited reserves to more than ten times the initial estimate.

The remaining five discoveries (Sarcee, Chinook Ridge, Mountain Park, Stolberg, Lovett River) are credited with reserves of 270 billion cubic feet, based on about 1,000 acres per discovery. By analogy, it is suggested that the ultimate recovery of the resulting five fields might be in excess of 2,700 billion cubic feet and, thus the ultimate recovery of all nine fields should be 6,200 billion cubic feet instead of 3,900 billion cubic feet as estimated by the Conservation Board, an increase of about 60 percent.

In the Foothills Belt of Alberta, between 1944 and the end of last year, 46 deep wildcats have been drilled resulting in the nine discoveries mentioned above. We have plotted the cumulative additions to reserves versus the cumulative number of deep wildcats on a graph (Exhibit 5) to determine if a trend can be recognized and, in this area, it would appear that, on the average, at least 125 billion cubic feet of gas have been discovered for each wildcat drilled. In preparing the graph, we have used the Conservation Board estimate of 3,500 billion cubic feet for the four partly-developed fields but, ten times the discovery well reserves or 2,700 billion cubic feet, for the five additional discoveries.

On the basis of the number of tests already completed or drilling this year, we estimate that at least 15 wildcats will be completed during 1958. If the incentive is provided to continue even this moderate rate of drilling, we expect that at least 1,800 billion cubic feet of gas will be added to the Foothills reserves each year. The first 1958 discovery (Panther River) has already added substantial amounts.

What we have tried to show in the Foothills Belt is that the reserves discovered are proportional to the number of wildcats drilled following reasonable exploration techniques. Naturally, the number of wildcats drilled depends on incentive. It is interesting to observe that the industry, provided with the impetus of an additional market, starting deliveries, say, at the end of 1961, may well have reserves of 13,000 billion cubic feet in the Foothills Belt alone, an increase of 9,100 billion cubic feet over the present Conservation Board estimates by the time sales start.

We wish to point out that most of the reserves in this area have so far been found in Mississippian rocks and in structures apparent from surface geology although usually the presence of structure has been verified by geophysical means. We can see enough structures of this type alone to keep the industry busy wildcatting, at the rate we predict, through 1961. If incentive continues, we believe that many buried structures, not apparent at the surface, will be found by geophysical methods. Furthermore, our recent discovery of gas in the Devonian formation at Panther River opens up possibilities of reserves in a new zone in all structures where this formation has not been tested.

VI. INCENTIVE FOR EXPLORATION

1. We discuss below our ideas of the incentive motivating Shell to explore for oil and gas reserves in Western Canada. We will give, firstly, a brief outline of the cash position of our exploration and production activities illustrating the incentive for exploration for oil and gas combined and, secondly, using our Jumping Pound field as an example, the incentive for gas alone.

Table VI is a cash flow statement of Shell's exploration and production activities. We have shown simply the total money spent and the income received during the period 1949-1957 and the expense and income during the year 1957.

Table VI

Cash Flow Statement

	(Thousands of Dollars) 1957	Accumulative 1949-1957
Income from oil and gas after royalty	12,636	33,814
Expenditures:		
Production operations	4,158	17,997
Administration, Services, etc.	4,138	19,107
Exploration & Development Capital	26,470	164,688
Total	34,766	201,792
Deficit	22,130	167,978

The above figures take no account of the interest cost of obtaining these moneys.

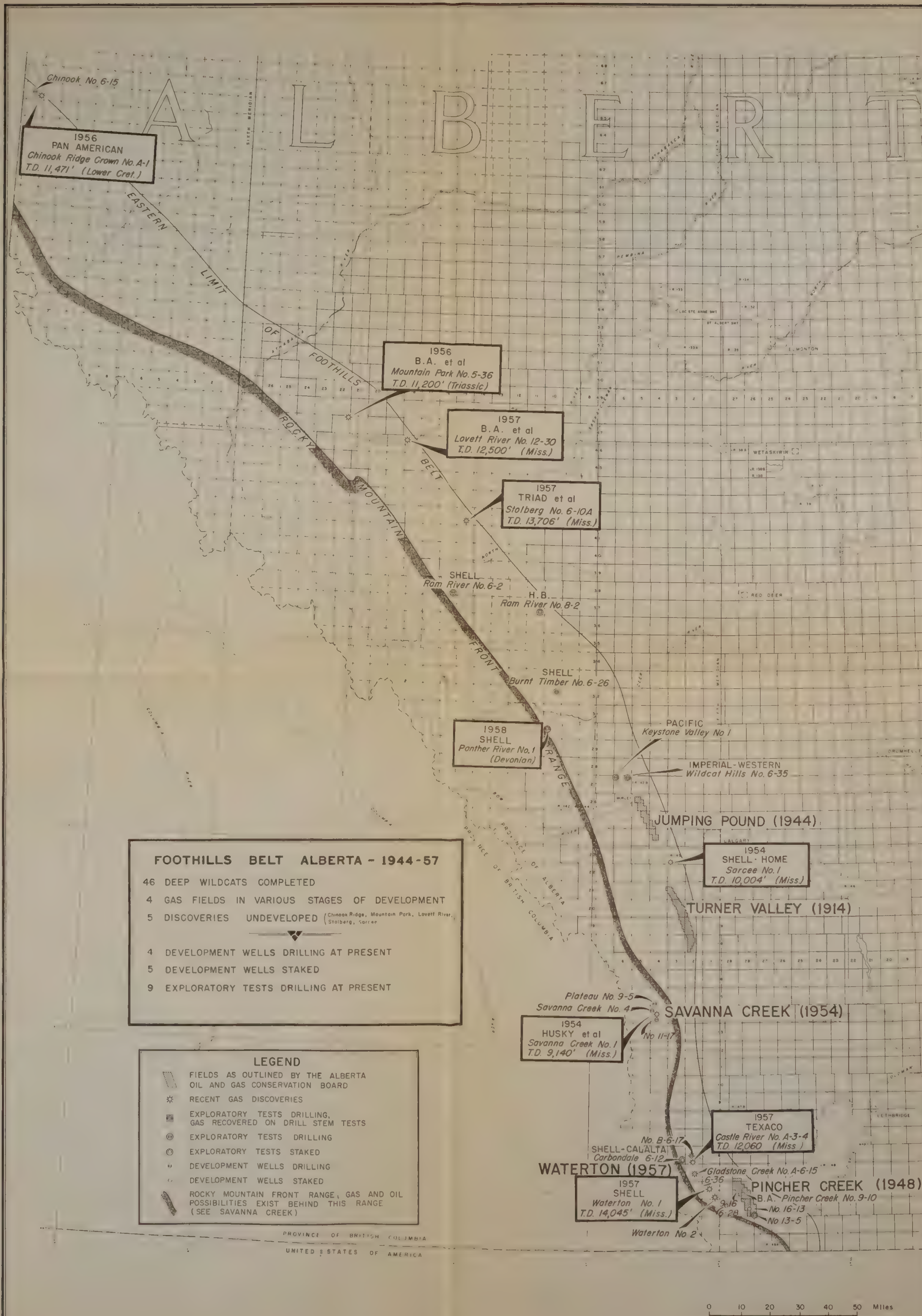

ALBERTA
Chinook No. 6-15
1956
PAN AMERICAN
Chinook Ridge Crown No. A-1
T.D. 11,471' (Lower Cret.)
EASTERN LIMIT OF FOOTHILLS BELT
ROCKY MOUNTAIN FRONT RANGE
1956
B.A. et al
Mountain Park No. 5-36
T.D. 11,200' (Triassic)
1957
B.A. et al
Lovett River No. 12-30
T.D. 12,500' (Miss.)
1957
TRIAD et al
Stolberg No. 6-10A
T.D. 13,706' (Miss.)
SHELL
Ram River No. 6-2
H.B.
Ram River No. 8-2
SHELL
Burnt Timber No. 6-26
1958
SHELL
Panther River No. 1
(Devonian)
PACIFIC
Keystone Valley No 1
IMPERIAL-WESTERN
Wildcat Hills No. 6-35
JUMPING POUND (1944)
1954
SHELL - HOME
Sarcee No. 1
T.D. 10,004' (Miss)
TURNER VALLEY (1914)
PROVINCE OF ALBERTA
PROVINCE OF BRITISH COLUMBIA
FOOTHILLS BELT ALBERTA - 1944-57
46 DEEP WILDCATS COMPLETED
4 GAS FIELDS IN VARIOUS STAGES OF DEVELOPMENT
5 DISCOVERIES UNDEVELOPED (Chinook Ridge, Mountain Park, Lovett River, Stolberg, Sarcee
4 DEVELOPMENT WELLS DRILLING AT PRESENT
5 DEVELOPMENT WELLS STAKED
9 EXPLORATORY TESTS DRILLING AT PRESENT
Plateau No. 9-5
Savanna Creek No. 4
SAVANNA CREEK (1954)
1954
HUSKY et al
Savanna Creek No. 1
T.D. 9,140' (Miss.)
No 11-17
LEGEND
FIELDS AS OUTLINED BY THE ALBERTA OIL AND GAS CONSERVATION BOARD
RECENT GAS DISCOVERIES
EXPLORATORY TESTS DRILLING, GAS RECOVERED ON DRILL STEM TESTS
EXPLORATORY TESTS DRILLING
EXPLORATORY TESTS STAKED
DEVELOPMENT WELLS DRILLING
DEVELOPMENT WELLS STAKED
ROCKY MOUNTAIN FRONT RANGE, GAS AND OIL POSSIBILITIES EXIST BEHIND THIS RANGE (SEE SAVANNA CREEK)
1957
TEXACO
Castle River No. A-3-4
T.D. 12,060 (Miss)
No. B-6-17
SHELL-CALALTA
Carbondale 6-12
WATERTON (1957)
Gladstone Creek No. A-6-15
6-36
PINCHER CREEK (1948)
1957
SHELL
Waterton No. 1
T.D. 14,045' (Miss.)
B.A. Pincher Creek No. 9-10
9-16
6-28
No. 16-13
No 13-5
Waterton No. 2
PROVINCE OF BRITISH COLUMBIA
UNITED STATES OF AMERICA
CALGARY
EDMONTON
WETASKIWIN
RED DEER
LETHBRIDGE
0 10 20 30 40 50 Miles

EXHIBIT - 4

FOOTHILLS BELT
ALBERTA

CUMULATIVE ADDITIONS TO GAS RESERVES AND WILDCATS DRILLED SINCE 1944

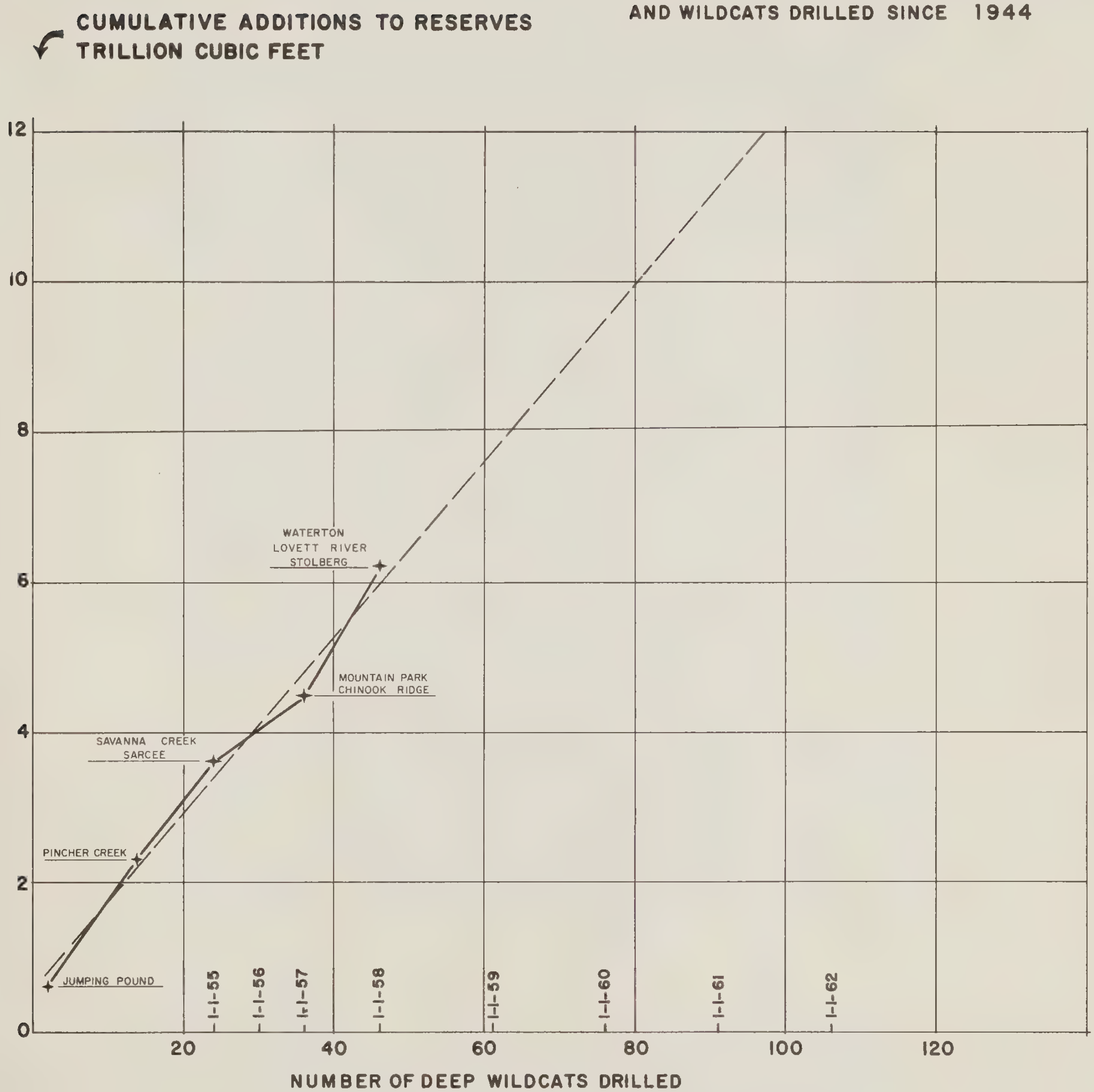


EXHIBIT-5

Over the past eight years, we have had to make up an average of $20 million dollars in cash each year and have accumulated a total deficit of $168 million. During 1957, our operating income, after production expenses, was about $8.5 million and if we had ceased all investment at the end of 1957 it would take 20 years, at this rate of income, to pay back the deficit. In the above figures, it will be noted that nothing has been included for the cost of unreturned capital and, therefore, the 20-year payout inferred is the shortest that could possibly be considered.

Our reserves of oil at the end of 1957 were 93 million barrels which would last approximately 20 years if we could continue the 1957 production at a constant rate. Our reserves at Jumping Pound (which is the only gas field out of which we are producing any substantial amount of gas) also are sufficient to produce the field for approximately 20 years at the 1957 production rate. From the above, it is obvious then that if we could produce oil at the 1957 rate and gas from Jumping Pound at the 1957 rate for a period of 20 years, we would just get back the capital we have expended, again allowing nothing for the cost of the outstanding capital. Further, it follows that any profit we expect to make will have to come from future discoveries of oil and gas or from the sale of gas from fields already discovered but for which we have no market.

We have attempted to show that Shell has risked a large capital investment in Canada and we believe from the figures given it is self evident that we have taken a very long-range view of this investment and we are prepared to accept a very slow return on our money. The fact that we are continuing to invest demonstrates that we believe we can find oil and gas reserves in Western Canada and that markets for our production will become available.

Incentive to Develop Gas Reserves

The oil and gas industry can do the drilling necessary to establish the proven reserves of gas required. We will try to illustrate that the industry cannot, in its good judgment, continue to make the required substantial expenditures without proper incentive and that such incentive must be greater than what is presently available to the supplier of foothills gas to the utilities of Alberta.

We have used the history of our Jumping Pound gas project as an example of how little incentive there is for gas producers under the conditions of limited markets and non-competitive prices.

The Jumping Pound field was the first non-associated gas field in Canada to be developed, the sour gas production treated in a modern plant and the residue dry gas sold to a local utility. It is one of the main sources of supply for the Canadian Western Natural Gas Company Limited for the City of Calgary and the Banff line which serves the City of Banff.

During the period from 1941-1947 Shell drilled seven wildcat wells in Southern Alberta. Of these none discovered oil and only one found gas production, the latter being Jumping Pound Unit No. 1, the discovery well in the Jumping Pound field.

Production at Jumping Pound is from the Turner Valley formation of Mississippian limestone, the wells being drilled to a depth of approximately 10,000 feet at costs exceeding $250,000.00 each.

In 1945 the Jumping Pound Unit was formed by agreement between Shell, the Province of Alberta, freehold lessors and royalty owners. This agreement provided for the orderly development of the field.

By 1947, four wells had been drilled, of which two were abandoned. In 1947 drilling was discontinued because there was no market for the gas, but in 1950 by reason of an increase in gas requirements in Southern Alberta, Shell was able to contract with Canadian Western Natural Gas Company Limited for the delivery of Jumping Pound gas.

Between 1950 and 1954 Shell drilled ten more wells, one of which was not commercial and was later abandoned. The drilling confirmed the existence of a complex geological structure and established the field as being some twelve miles in length and averaging about one mile in width.

A gas processing plant was completed and placed on stream in the spring of 1951 delivering sweet gas to Canadian Western. This initial plant which had a capacity of 25 million cubic feet per

day was expanded in stages to 35, to 60, and finally in 1957 to 90 million cubic feet per day of merchantable gas. The contracted average daily sales volume of the plant at its present rated capacity of 90 million cubic feet per day is expected to be approximately 60 million cubic feet per day.

The contract with the utility company is for a period of ten years, commencing May, 1951, and provides for a price of 10¾ cents per M.C.F. at the tailgate of the plant.

The plant process includes removal of liquid hydrocarbons, hydrogen sulphide, carbon dioxide and water vapor. The liquid hydrocarbons are recovered and sold, the hydrogen sulphide is manufactured into elemental sulphur and sold, and the carbon dioxide and water are removed and vented.

The attached Exhibit 6 shows the above mentioned trend of plant development by years, indicating the difference between contracted sales volume and the plant capacity required to handle a 70 per cent load factor. With no more than the local market available at any time the plant had to be installed in this stepwise manner. This resulted in greater expense than under the normal conditions where an adequate market exists and major construction can be completed as one job.

Exhibit 7 further illustrates the effect of load factor on operations on a monthly basis with deliveries during some months being as low as 25 per cent of the plant's capacity.

These charts illustrate the effective plant capacity that must be held in readiness to meet peak demands. We stress this condition of load factor as it is most important in the economics of a plant where facilities, material and labor must always be provided for capacities well in excess of contracted average daily sales volumes.

At present the cumulative investment in the plant and field facilities alone has reached $12 million. The return of this investment is still many years away because of the low load factor for

the reserve and the low price available in a restricted market which exists even today in the absence of any major outlet in the foothills area. The following cash flow statement illustrates the actual position of the Jumping Pound gas production and processing project under the above conditions.

TABLE VII

CASH FLOW STATEMENT — JUMPING POUND PLANT AND FIELD

ACCUMULATIVE 1941 — 1957

	(Thousands of Dollars) Including Finding Costs	Excluding Finding Costs
Income after Royalty	$11,509	$11,509
Expenditures:		
Production Operations	3,949	3,949
Administration, Overhead, Sundry	3,154	1,714
Exploration	4,474	—
Capital Expenditures (Development wells, plant and land)	12,239	12,239
Total	$23,816	$17,902
Deficit	$12,307	$ 6,393
Interest on Outstanding Capital @ 5½%	$ 7,303	$ 3,182
Deficit including interest charges	$19,610	$ 9,575

On the basis of our experience to date, and looking into the future and assuming (1) that the same gas prices will exist (although we hope that they will be improved), and (2) that the same costs of developing gas fields and building gas treating facilities will prevail (although we expect them to continue to go up), and (3) that we credit our outstanding capital at 5½ per cent interest we might look at the project about like this:

Including finding costs and using the principle that the first dollar in is the last dollar out, the first dollar would be the one spent in the first wildcat well drilled by Shell in Alberta. This dollar would not be returned until 1973, or 32 years later. But because it is difficult to allocate finding costs, let us exclude them and assume that the first dollar spent was for the discovery well at Jumping Pound. Under the conditions which have existed and which now

exist, this dollar would not be paid back until 1963, or about 20 years after spending.

Knowing what we do about slow market build-up, costs and the low prices for gas, we feel that under the conditions which have existed the Jumping Pound project was a poor investment. Consequently we feel that if those conditions were to continue it would be impossible for us to recommend that substantial expenditures be incurred in the search for and development of natural gas reserves in the foothills of Western Canada.

We are confident of our ability to find substantial reserves of gas and we are presently optimistic about improved conditions for gas exploration, market volumes, load factors and prices. Should it transpire that this optimism is not justified, we would have to give serious consideration to the advisability of revising our exploration plans.

Importance of Production Rate

The importance of production rate on the economics of a plant like Jumping Pound prompts us to comment on the so-called 30-year rolling supply which has been discussed at these hearings.

We wish to point out that such a requirement is much more stringent than it may first appear. When considered along with our own and the industry's calculation of the gas prospects of Western Canada it does not help but rather serves to aggravate the poor incentive conditions summarized earlier.

Most forecasters estimate that the needs of Canada will triple in the next 30 years. It is not difficult to see that the reserves which must be set aside to take care of these needs on a 30-year rolling supply basis will represent a gas volume equivalent to 60 years supply at the initial rate. When we consider what the position will be, say, 10 years after sales start, we are certain that the requirements for the following 30 years will also be equivalent to 60 years at the then prevailing rate. In fact, at any moment the 30-year rolling supply calls for reserves equivalent to 60 years supply at the then current rate.

Furthermore, as additional fields are set aside to meet future requirements it would be reasonable to expect these fields to be connected to the transmission systems so that the operators can obtain some return. The concept of a 30-year rolling supply thus means that each field will produce over a life of 60 years. From the standpoint of the life of wells and plants and profitability, this would be completely unrealistic. We therefore suggest that the Commission consider a policy by which the life of a field would be fixed at a realistic period based on sound engineering and economic considerations.

VII. SUMMARY

Shell's views in summary might be stated as follows:

The sedimentary basin of Western Canada has had an enormous capacity for the generation of hydrocarbons.

There remain in Western Canada from this generating process, tremendous quantities of recoverable oil and gas.

The published estimates of the reserves of oil and gas are for the most part substantially lower than is justified.

The growth of reserves of natural gas depends directly on the amount of exploration which is conducted. The relative magnitude of such growth is illustrated by our experience in a section of the Foothills Belt of Alberta.

The extent of any exploration effort will depend entirely on the incentive to explore. In our own case the overall incentive present in the past has resulted in our taking a very long-range view of profitability. However, the incentive, or lack of it, to search for gas over the past years would preclude a repetition by our company of the type of operation which we have conducted at Jumping Pound. Such an operation requires much greater incentive in the type of market available. In other words a gas market is vital to the continuance of such an investment.

COMPARISON OF YEARLY AVERAGE
AND PLANT CAPACITY REQUIRED TO
MEET SEASONAL PEAK DEMANDS

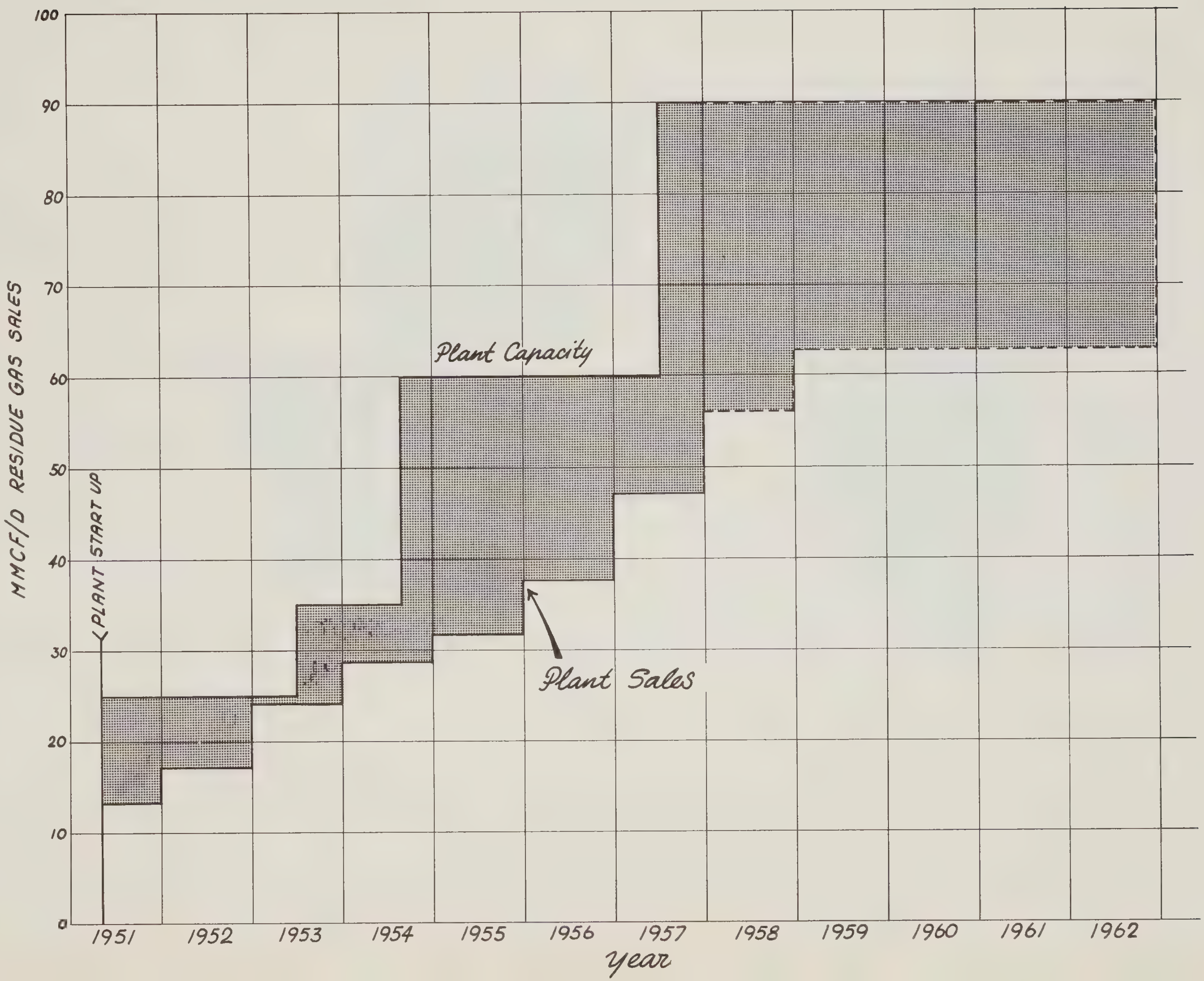


EXHIBIT - 6

SEASONAL VARIATIONS OF PLANT
RESIDUE GAS SALES

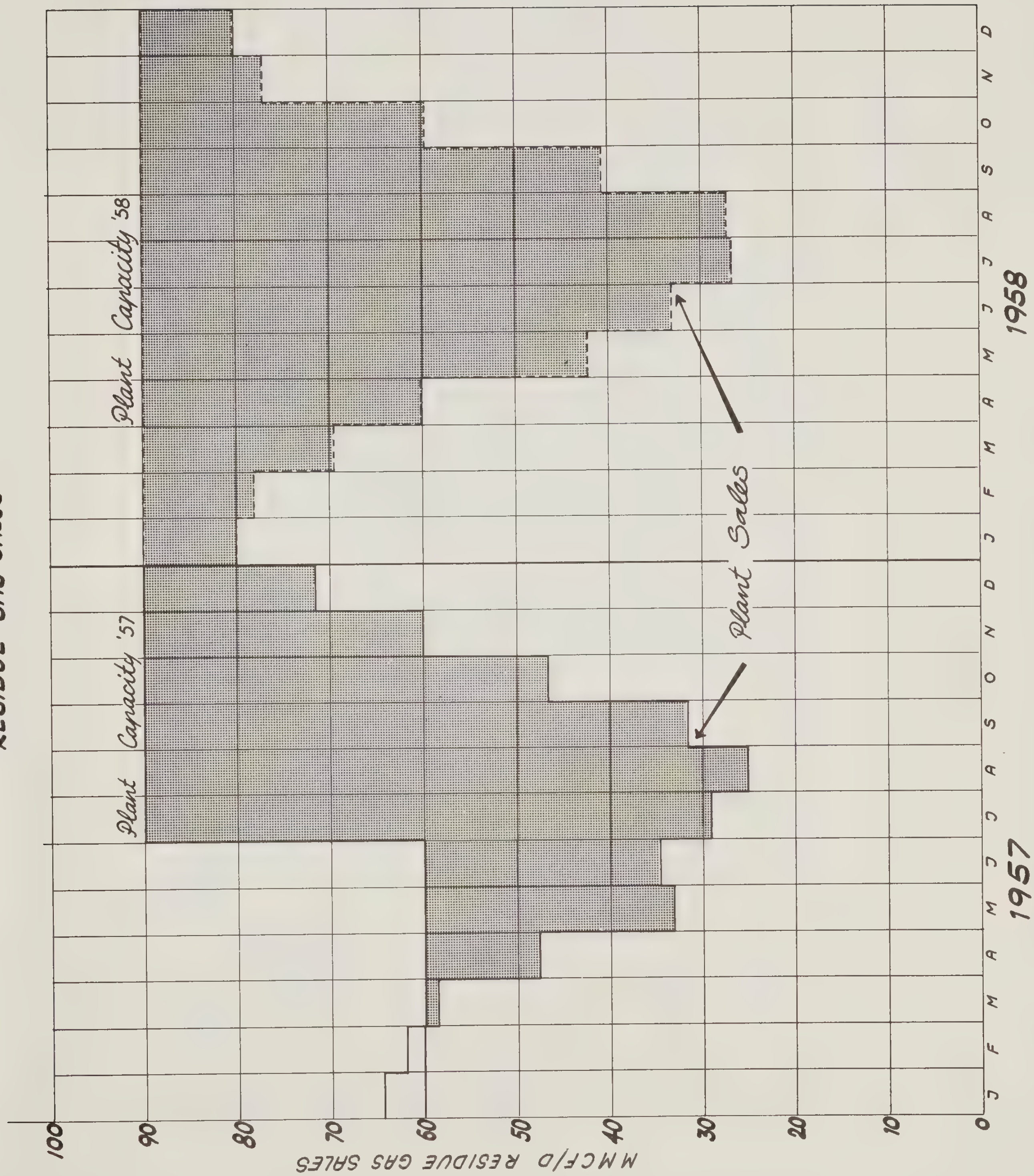


EXHIBIT-7

Section II

DISPOSITION OF CANADIAN CRUDE

Production History

Production of crude oil in Canada increased from 20 thousand barrels daily in 1947 to 504 thousand barrels daily in 1957. The initial discoveries in Alberta displaced rail shipments of crude from as far away as Texas and Louisiana. Refinery capacities were built up in the Edmonton area and some products began to move into Saskatchewan by road and rail. By 1950 the forward potential of both production and markets was such that a group of the major oil companies formed the Interprovincial Pipe Line Company which financed and built a pipe line from the West to the head of the Great Lakes. By 1953 the oil companies were looking to the western market and another group formed the Trans Mountain Oil Pipe Line Company which financed and built a pipe line to Vancouver. Thus, by 1954 Prairie crude oil was reaching Canadian refineries from Vancouver to Sarnia (See Exhibit 8 (A)). Alberta, in addition to supplying refineries in Ontario and British Columbia, also made up crude deficiencies in the other Prairie Provinces. Saskatchewan became self-sufficient in 1956 but Manitoba is still deficient on over-all crude requirements.

Domestic Markets

Ontario is clearly becoming the largest regional consumer of Canadian crude, taking an estimated 141 thousand barrels daily last year. The three Prairie Provinces still had a slight advantage over Ontario in 1957 but this is expected to be eliminated during 1958.

Use of Canadian Crude Oil	1954	1955	1956	1957	1958 (Est.)	% Increase 1958 over 1954
		(MB/D)				
Prairie Provinces	124	142	155	148	162	30.6
Ontario	91	113	135	141	170	86.8

The marked increase in Ontario consumption anticipated in 1958 is due to the recently completed refinery expansions in the

Toronto/Hamilton area. Exhibit 8 (B) illustrates the nature of the Ontario market for crude oil in more detail, dividing the Province into two, taking Sarnia and Fort William as the West and the Toronto/Hamilton area as the East. In 1957, Western Ontario required 116 thousand and the East 43 thousand barrels daily. Of this total, 17 thousand barrels were imported daily from the United States of America.

Ontario	1957			1958 (Est.)		
	West	East	Total	West	East	Total
Canadian Crude.....	99	42	141	104	66	170
Imported Crude.....	17	1	18	17	1	18
Total..............	116	43	159	121	67	188

Thus Ontario consumption of Canadian crude may be expected to increase by 29 thousand barrels daily, or 20.6 per cent during the current year. Refinery construction currently under way in the Toronto/Hamilton area will add another 20 thousand barrels daily in 1959. These refinery additions will replace immediately and directly products manufactured in Montreal from imported crudes. It would seem logical that all refiners in Ontario presently having access to Canadian crude by existing pipe lines, should nominate western oil. Such a move would add 18 thousand barrels daily to the demand for Canadian crude raising Ontario requirements 33.3 per cent above the 1957 level.

British Columbia is the third domestic regional consumer of Canadian crude. There consumption of Canadian crude has increased from 37 thousand in 1954 to an estimated 73 thousand barrels daily in 1958 for a 97.3 per cent gain. This Province has enjoyed the most spectacular rate of development in the post-war decade. Continuing refinery construction in British Columbia is the oil industry's expression of confidence in the future of this area.

Geography of Imports

Turning to importing areas, Quebec and the Maritime Provinces are the most important. (See Exhibit 8 (B)). The Province of Quebec

imported 253 thousand barrels daily of crude oil during 1957 of which 206 thousand came from Venezuela, 39 thousand from the Middle East and the remainder from the United States of America and Trinidad. The Maritime Provinces imported 35 thousand barrels daily from Venezuela. It should be pointed out that crude imports have been of declining significance in Eastern Canada since 1950. In that year total refining capacity in Eastern Canada was 241 thousand barrels daily and crude imports 208 thousand, or 86.3 per cent. By 1957 this ratio had fallen to 60.0 per cent and in 1958 a further decline to 55.2 per cent is anticipated due to refinery expansions within the present orbit of Canadian crude oil.

Export Markets

Crude oil exports to the United States on a significant scale began in 1955 with 34 thousand barrels daily going to the Pacific North West states and 14 thousand barrels daily to points in the United States midwest (Exhibit 9 (B)). These logical markets both grew steadily through 1957 to a total of 133 thousand barrels daily. In 1956, however, Canadian producers received an unexpected bonus in the form of offshore shipments to California made possible by distortions in international oil movements brought about by the Suez crisis. At the time, it was generally accepted that these were spot or temporary movements and consequently despondency or alarm, when these shipments stopped, as they did in July 1957, was not justified.

The emergence of Saskatchewan as a major producer of crude oil is one of the most significant developments in recent years. From 1951 to 1957 Saskatchewan production increased from 3 to 100 thousand barrels daily. Over the same period Alberta production gained from 126 to 383 thousand barrels daily or 204.0 per cent. The more rapid advance of Saskatchewan production increased its share of total western crude output from 2.3 per cent to 20.0 per cent or 770 per cent. Most recent estimates of proven crude oil reserves indicate Alberta to have 2,722 million barrels and Saskatchewan 421 million barrels.

Saskatchewan's Advantage

In spite of smaller reserves so far found, Saskatchewan has many advantages over Alberta. Geographically, the south-east

corner of Saskatchewan, where the most active fields are located, is approximately 600 miles closer to Eastern Canada and United States Upper Mid-Continent markets. In terms of trunk pipe line tariff, this represents a saving of about 12 cents per barrel. Secondly, Saskatchewan producers have no over-all pro-ration. Yet still producing according to good engineering standards, and sound conservation principles, they have been able to enjoy more flexibility in moving into new market areas as production became available. The first of these advantages would yield only to substantial discoveries in Manitoba, even closer to market. The second advantage—no need for pro-ration — may well remain.

The changing pattern of crude exports to the United States is a reflection of Saskatchewan development. Shipments to United States Upper Mid-Continent points reached 33 thousand barrels daily in 1957, while Alberta movements to the same area declined slightly to 17 thousand barrels daily. This seems to be a likely growth for Saskatchewan production. In 1958, the increase in crude exports to this area should largely offset the decline in volumes moved to the Pacific North West states.

Crude Exports To:	Thousands of Barrels Daily 1957	1958 (Est.)
United States Upper Mid-Continent....	59	80
United States Pacific North West......	74	45
	133	125

Loss of Canadian Crude Market in U.S. North West

The only export market which has in effect been lost in 1958 is the offshore movement to California, which has already been explained as a windfall situation. In the case of the Shell Oil Company refinery at Anacortes, Washington, the reduced volume of Canadian crude imports has been due to cut-backs in refinery throughputs and not to displacement by other foreign crudes. The Pacific North West states have felt the full impact of the current economic slowdown and problems of slackening demand and long inventories have been pronounced, leading to the current temporary reduction in crude runs.

Saskatchewan Gain not at Expense of Alberta

It may seem that the Saskatchewan producers have gained at the expense of their neighbours in Alberta, but Exhibit — 9(A) shows that this is not so. Saskatchewan crude is serving an area in the United States which is at present comparatively isolated from competitive sources, whereas the markets recently lost by Alberta producers are on tidewater on the West Coast and this area cannot be regarded as being exposed to competition from Saskatchewan producers. The fact is that domestic and export markets must be served from the most economic source and it is on this sound basis that Saskatchewan production has enjoyed such healthy increases over the last few years.

Now Saskatchewan crude oil has a higher than average sulphur content. Some refiners in Eastern Canada can only use this feedstock when blended with other sweeter crudes, principally from Alberta. On the other hand, certain refiners in the United States Upper Mid-Continent area have designed refinery installations specifically to handle the sour crudes from Saskatchewan fields. It would seem that once these investments had been made and the refinery economics established on the basis of the cheap, sour crude, these United States refiners should be stable importers of Saskatchewan crude at increasing levels.

7? Sandia

wording

Encouraging Overall Picture

This picture of the outlets for Canadian crude oil is an encouraging one. In the Prairie Provinces the diversification and development of recent years, which has been partially generated by oil and gas activities, will continue to provide a steadily growing market for local crudes. In Ontario, with the reach of Canadian crude stretching further eastward to Toronto and strengthening steadily, this must surely be regarded as the most promising development as western producers share the remarkable industrial prosperity of this Province. This optimism must also apply to the British Columbia market based as it is upon its wealth of natural resources. Finally, we have the prospect of growing exports to the United States. Temporarily reduced on the West Coast and growing steadily in the heart of the continent, there can be little doubt that Canadian crude oil producers will enjoy increasing markets in these areas.

History of Crude Imports

With domestic crude production of 20 thousand barrels daily and refining capacity of 245 thousand barrels daily, imports of crude oil into Canada played a dominant role in 1946. It was not until 1950 and the Interprovincial Pipe Line that the volume of crude imports began to level off as Canadian crude began to feed the Sarnia area. (See Exhibit — 10.) From 1950 till 1955 declining imports into Ontario offset increasing movements into the Maritimes and Quebec, but thereafter the total began to increase once more in response to refinery expansions in the Montreal area. Imported crude has, however, been declining in relative significance in Eastern Canada since 1950. In that year, crude imports amounted to 86.3 per cent of refining capacity.

Future of Crude Imports

In 1958 imports are estimated to be 55.2 per cent and there is every reason to believe that this share will decline in the next few years as refining capacity in the Toronto area is increased. In 1959, when current refinery construction in this area is completed, the ratio will be reduced to 53.0 per cent. As refining capacity is enlarged in the Toronto/Hamilton area the radius of economic product distribution will push eastward, displacing Montreal refined products. This displacement will, in turn, free refining capacity in Montreal which will then be available to absorb future growth in the Quebec market without necessitating increases in capacity or crude imports. Our own company expects to build a refinery near Bronte, Ontario, in 1960. It is designed to run Canadian crude and to displace products from our Montreal East refinery currently being moved by pipe line into Southern Ontario. By so doing we will, in effect, be reducing our dependence on imported crude.

A Solution to the Problem

The Toronto/Hamilton area is one of the most rapidly developing regions in North America. Residential, commercial and industrial expansion and population increases have all been involved. Until as recently as last year, refining capacity in this area was only 35 thousand barrels daily, running imported and domestic crude, with

the balance of supply being moved by product pipe lines from Montreal (60 thousand barrels daily) and Sarnia (145 thousand barrels daily). By 1959 local refining capacity in the Toronto/Hamilton area will be 110 thousand barrels daily, running entirely on Canadian crude. By 1963 the volume of domestic crude processed in this area should approach 150 thousand barrels daily. The effect will be the "backing up" of products refined in Montreal from imported crude and replacing them with products refined locally from domestic oil. Or put differently, spare refining capacity in Montreal for the future growth of that area, will be created by the construction of refinery capacity in Ontario. This is the classic way, in the natural play of supply and demand, in which markets have ever developed in a free economy.

Product Imports

Product imports into Eastern Canada have also been declining in significance since 1951 (See Exhibit 11). At that time they amounted to 22.8 per cent of total demand for petroleum products, while the estimate for 1958 is 17.7 per cent.

These imports have consisted principally of aviation fuels and middle distillate heating oils. The yield structure of Canadian refineries in the aggregate has been unable to provide adequate middle distillate production to cover the remarkable growth in demand of the post-war years. This rate of increase is now expected to level off as saturation points are approaching in railway dieselization, and conversion to oil heat installations. Natural gas is now available in the metropolitan centres of Eastern Canada and this will further retard the rate of increase in distillate demand.

In the case of aviation fuels the rapid growth of turbine and jet-powered aircraft is helping to reduce imports. As conventional propeller-driven aircraft requiring high octane aviation gasolines are replaced by turbine-powered types using lower cut gasolines and distillate blends, domestic refiners will be able to satisfy a larger part of the overall aviation fuel demand.

It seems unlikely, therefore, that product imports into Canada will increase significantly beyond present levels and in the near future a downward trend may be expected.

Price Structure

The basis of field prices of Canadian crudes has evolved systematically since 1947. As crude production increased in Alberta it had to move further and further to market outlets. The further the haul the lower the wellhead netback as more transportation charges had to be absorbed by the producer. But until Canadian crude had to compete directly with some other major source, Alberta wellhead prices were isolated from external influences. When the Interprovincial Pipe Line moved Canadian production to Sarnia a substantial reduction was necessary to equate Alberta wellhead prices to competing Illinois crudes laid down at Sarnia. Thus, before the pipe line completion, Redwater wellhead price was $2.88 per barrel, but by mid-1951 had fallen to $2.46 per barrel. Illinois crude laid down at Sarnia became the base point upon which Canadian crude was priced. Today, with Illinois at $3.00 and Redwater at $2.56 they lay down at Sarnia within 1 cent per barrel of one another (Exhibit 12). The price of moving into these new market areas has been exposure to the forces of competitive crudes. The further from the wellhead the crude is moved, the more susceptible the netback price becomes to these factors and the greater is the freight absorption necessary to make the move.

Canadian Crude in the Montreal Market

It has been suggested that Canadian crude be moved by pipe line into the Montreal area as a means of creating a market outlet for shut-in production in Alberta. In order to force the economics of this move, certain proposals have been made, all of which seem to be open to criticism.

Dangerous Artifices

If the pipe line freight charge to Montreal were lowered artificially by forcing intermediate offtake points to carry a disproportionate share of line operating costs, this would mean discrimination against consumers west of Montreal. Any such system of artificial controls creates more problems and inequities than it solves. If a system of accelerated depreciation were used to assist the investment, then again every consumer in Canada being served by a pipe line not enjoying this privilege would be discriminated against.

The imposition of a customs tariff on crude imports would, of necessity, be reflected in higher product prices in the Montreal refining orbit. Refiners in the Maritimes would have to pay the same tariff, even although they could not possibly use Canadian crude — an even sharper discrimination against the Maritimes consumer.

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The concept of raising a tariff wall to keep out imports implies that the commodity in question has a limited ability to overcome the barrier. But this does not apply to foreign sources of crude oil currently being imported into Eastern Canada. All are in areas enjoying lower finding and development costs. Most are countries whose very economic existence depends upon exports of crude oil and its products. Retaliation, by price and other concessions, in order to retain their traditional hard-currency markets in Eastern Canada, cannot be excluded. The implications in terms of revenue to provincial government and producer alike are obvious.

Quotas

It has been suggested the answer to this is a system of quotas. A quota system similar to that currently being administered in the United States would be impractical in Canada for several reasons. If a quota meant that only part of the Montreal refinery requirements would be met from Canadian crude sources, this would pose many problems from an investment viewpoint. Even if the quota were 50 percent of crude runs, this volume would not justify the very favourable pipe line tariffs being assumed in certain proposals. In a word, it is unwise to tamper with the natural balance of economic forces. Take the example of the Montreal refiners and those in the Maritimes. A system of quotas restricting foreign crude imports into Montreal would give Maritime refiners an artificial competitive advantage. As Quebec refineries were compelled to a diet of high-cost crude, the unrestricted Maritime refiners would be able to infiltrate the Montreal refiners' market.

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Implications for Canada's Merchant Fleet

Construction of a pipe line to Montreal would also dislocate part of Canada's merchant marine. My company alone has three ocean tankers engaged in crude movement to Montreal. These

vessels sail under Canadian registry and carry Canadian crews. We have an additional supertanker under construction in Quebec, designed specifically for this trade. Harbour facilities at Montreal and Portland represent an important investment. In part or in all, these would be made redundant by a pipe line from the west.

Shell's Interest in New Markets

The figures which we have disclosed earlier for our own company show that on a major part of our accumulated investment we have had no return, and will receive no return, at present production allowables, for some time to come. No one is more interested than our company in obtaining new markets for Canadian crude oil in which we can share and so improve our revenue and obtain a return on our very substantial investment in Western Canada. What we fear is a failure to resist the temptation to cure a short-term cyclical difficulty by basically uneconomic measures which possess serious long-term dangers for Canada's economy and which can only be sustained by artificial means.

Who gains by Artifices

The whole discussion of moving Canadian crude to Montreal has been prompted by the temporary difficulties of certain producers in Alberta. But would a pipe line to Montreal really help the Alberta producer? There is no guarantee that once this proposed line was built the Montreal refiners would nominate Alberta crude. Saskatchewan has the advantage of geography, wellhead price and unfettered production. The sour crudes of Saskatchewan might be very acceptable to certain Montreal refiners who are well equipped to handle this type of material. It might well be that the plan — if indeed it is designed to help the Alberta independent producers — might not achieve this end so much as to increase movements of Saskatchewan crude.

Loss of Revenue Resulting from Artifices

Finally, by moving Canadian crude into Montreal by pipe line a new — and lower — price structure would surely evolve as Canadian producers were forced to compete with foreign sources and fluctuating tanker rates. As more and more so-called "supertankers"

are built, replacing the higher cost T-2's inherited from World War II, it seems likely the present low rates will be maintained. Some of these new, larger vessels can actually operate profitably at rates below those assumed in the calculations used in this brief (United States Maritime Commission minus 40 percent).

Existing Large Investment not Based on Artifices

The oil industry in Eastern Canada has truly grown up in the post-war decade and leads in many ways the remarkable industrial development of Canada. There has evolved an intricate pattern of supply, manufacture and distribution of petroleum products based upon logical economic principles. The nation's largest refining centre has mushroomed at Montreal where an estimated $300 million has been invested in refining units alone. A further sum of about $200 million has been invested in the Portland/Montreal Pipe Line and numerous deep sea tankers. This system of supply recognizes the fact that ocean-borne crude is traditionally cheaper than crude borne over any great land distance. A policy involving tariffs or quotas designed to restrict the free flow of deep water crude supply must inevitably jeopardize such investments, on which, it should be mentioned in passing, substantial debt remains outstanding.

Vulnerable Economics

To build a crude oil pipe line from Western Canada to Montreal is an expensive and unfortunately escape-barred venture. It is escape-barred because, before it can be built, it will commit both refiner and producer to a price structure which they both may well regret. The refiners must pledge themselves to a high cost source of raw material, relative to cheaper ocean-borne crudes. Producers must commit their crude to a distant market, exposed to the competition of the most competitive crude sources in the world, as other economically situated growth markets become available closer at hand — a $250-$300 million investment which cannot show long-term economic justification. In our view, by ordinary commercial standards, this pipe line cannot be financed.

Conclusion

Possibly in conclusion one can look at this problem in an even wider field of vision. The importation of crude oil into Eastern

Canada is only one aspect of the intricate network of international trade from which Canadians derive their livelihood. International trade depends upon the relative costs of producing various commodities in different countries. Commodities move from countries where they are comparatively cheap in real costs of production, to countries where these comparative costs are higher. And these costs must include elements of transportation charges, especially in a country the size of Canada. Thus surely it is to Canada's net advantage to import crude oil into the Eastern Provinces and pay for these imports in primary commodities such as cereals and forest products which can be produced in Canada at a lower cost. By so doing the real cost of petroleum-derived energy is minimized — a benefit not to some sectional interest — but to the greatest good of the greatest number of Canadians.

DISPOSITION OF CANADIAN CRUDE OIL PRODUCTION [1]
MB/D

1954 - 1958

	1954	1955	1956	1957	1958[2]
Production					
Alberta	240	311	393	383	380
Saskatchewan	15	31	56	100	129
Manitoba	6	12	16	17	17
B.C. & N.W.T.	1	1	2	3	3
Eastern Canada	1	1	1	1	1
TOTAL	263	356	468	504	530
Disposition					
B.C.	37	53	62	63	73
Alberta	60	69	74	71	75
Saskatchewan	43	49	54	52	58
Manitoba	21	24	27	25	29
Ontario	94	113	135	141	170
Sub-Total Canada	255	308	352	352	405
California	—	—	17	19	—
Pacific N.W. States	3	34	53	74	45
U.S. Mid-West	5	14	46	59	80
Sub-Total U.S.A.	8	48	116	152	125
TOTAL	263	356	468	504	530

(1) Does not include Natural Gas liquids

(2) Estimated

EXHIBIT — 8(A)

Disposition of Canadian Crude Oil Production and Imports — 1957

MB/D

Origin	Destination									
						Ontario				
	B.C. & N.W.T.	U.S. Pac. N.W.	Calif.	Prairie Provinces	U.S. Upper Mid. Cont.	West(1)	East(2)	Quebec	Maritimes	Total
Alberta	61	74	19	118	17	66	28	—	—	383
B.C. & N.W.T.	3	—	—	—	—	—	—	—	—	3
Saskatchewan	—	—	—	29	33	24	14	—	—	100
Manitoba	—	—	—	1	9	7	—	—	—	17
Eastern Canada	—	—	—	—	—	1	—	—	—	1
U.S.	—	—	—	—	—	17	—	5	—	22
Venezuela	—	—	—	—	—	—	—	206	35	241
Trinidad	—	—	—	—	—	—	1	3	—	4
Middle East	—	—	—	—	—	—	—	39	—	39
Totals	64	74	19	148	59	115	43	253	35	810

(1) Sarnia and Fort William
(2) Toronto/Hamilton area

Exhibit — 8 (b)

EXHIBIT — 9(A)

EXPORTS OF CANADIAN CRUDE OIL BY DESTINATION AND PROVINCE OF ORIGIN

1955 — 1958

(MB/D)

FROM:	ALBERTA				SASKATCHEWAN	MANITOBA	
TO:	Pacific N.W. States	Calif.	U.S. Mid-Continent	Total	U.S. Mid-Continent		Total
1955	34	—	10	44	4	—	48
1956	53	17	20	90	19	7	116
1957	74	19	17	110	33	9	152
1958(1)	45	—	17	62	53	10	125

EXHIBIT — 9(B)

TOTAL EXPORTS OF CANADIAN CRUDE OIL TO THE U.S.A.

1955 — 1958

(MB/D)

	Pacific N.W.	California	U.S. Mid-Continent	Total
1955	34	—	14	48
1956	53	17	46	116
1957	74	19	59	152
1958(1)	45	—	80	125

(1) — Estimated.

EXHIBITS — 9(A) & (B)

Exhibit — 10

Crude Oil Imports into Canada — 1950-1958
(MB/D)

Source of Imports	1950	1951	1952	1953	1954	1955	1956	1957	1958(1)
Venezuela	83	138	150	160	163	187	213	241	255
Trinidad	7	7	7	8	8	8	10	4	—
Middle East	49	23	19	17	18	23	49	39	55
U.S.A.	86	60	50	38	22	20	20	22	10
Total	225	228	226	223	211	238	292	306	320
Destination									
Maritimes and Quebec	158	162	168	177	181	211	264	288	310
Ontario	50	44	37	30	24	27	28	18	10
Total Eastern Canada	208	206	205	207	205	238	292	306	320
Total Canada	225	228	226	223	211	238	292	306	320
Refining Capacity in MB/D Eastern Canada (2)	241	262	291	329	332	376	448	510	580
Crude Imports into Eastern Canada as % of Refinery Capacity	86.3%	78.6%	70.4%	62.9%	61.7%	63.3%	65.2%	60.0%	55.2%

(1) Estimated
(2) At year end

Exhibit — 11

Petroleum Product Imports into Canada — 1951-1958

(MB/D)

Source of Imports	1951	1952	1953	1954	1955	1956	1957	1958[1]	% Increase 1951 to 1958
U.S.A.	58	69	75	59	59	69	55	60	
Venezuela and N.W.I.	20	20	17	26	38	32	45	55	
Total	78	89	92	85	97	101	100	115	+47.4%
Destination									
Western Canada	14	16	17	16	18	19	17	17	
Eastern Canada	64	73	75	69	79	82	83	98	+53.1%
Total	78	89	92	85	97	101	100	115	
Total Demand in Eastern Canada	281	311	343	378	432	490	524	555	+97.5%
Product Imports to Eastern Canada as % of Total Demand	22.8%	23.5%	21.9%	18.3%	18.3%	16.7%	15.8%	17.7%	

(1) Estimated

Laid Down Costs of Selected Crudes at Sarnia

Illinois
(39.6° A.P.I.)

Wellhead	$3.0000
Gathering	.1000
P/L Allowance	.0313
P/L to Boundary	.2600
River Crossing	.0008
L/D Sarnia	$3.3921
Less U.S. Currency portion Interprovincial tariff	.3498
	$3.0423 U.S. funds

Redwater
(34.7° A.P.I.)

Wellhead	$2.5600
Gathering Allowance ½ of 1%	.0129
Gathering	.0400
P/L Allowance 1%	.0264
Marketing	.0100
Canadian portion Interprovincial tariff	.3102
L/D Sarnia	$2.9595
Currency adjustment @ 2.4%	.0710
	$3.0305 U.S. funds

Exhibit — 12

SECTION III

TAXATION

Introduction

We have now completed the first two main sections of our submission. The first covered oil and gas exploration and production, together with reserves and producibility, the matter of incentive, and the vital question of finding new markets — which means moving into a waiting export market. The second had to do with the disposal or marketing of Canadian crude oil. In both gas and oil, when we consider market outlets for Canada's substantial reserves, we are dealing with matters not entirely within our own control. We now turn — in Section III — to an important factor in Canada's oil and gas economy, which it is in our power, and we submit in our national interest, to rectify.

At this point, therefore, it might be well to summarize what we have said so far. We have tried to show that:

1. Canada's oil and gas resources in the west are potentially of such magnitude as virtually to guarantee for the foreseeable future Canada's requirements of these forms of energy.

2. These underground supplies of petroleum will be brought to the surface and made available for the Canadian consumer if adequate incentive exists.

3. The experience of our company indicates that the short term incentive has been meagre and the past and continuing heavy investment of the industry, including Shell, is a long term proposition.

4. In the short term the outlook for the export growth of our oil markets has temporarily reached a plateau. But

5. There is an immediate export market for gas which Canada has the necessary reserves to supply, the revenue from which would tend to offset the loss from the temporary levelling of the oil markets.

6. Meeting a temporary short-term problem with measures having such grave long-term implications as forcing the heavy investment in a pipe line to Montreal, is a complex and dangerous step. Rather we advocate, in addition to taking the gas markets mentioned above, the construction of refining capacity in the highly economic area of the Toronto-Hamilton-Western Ontario markets now tributary to western crude oil.

Having made these points, we would turn to what is a most important difficulty — and one which it *is* in Canada's power to cure — facing Canadian oil in competing in world markets, as it now has to do. This is Canadian taxation. Canadian taxation presently places Canadian oil at a substantial disadvantage in its visible export markets. These markets lie primarily in the Upper Mid-Continent and Pacific Coast regions of the United States. Yet in comparative terms the tax differential between the United States oil and gas producer supplying those markets, and the Canadian producer attempting to supply them, represents a built-in penalty on the Canadian producer — of our own making — as a result of materially less liberal tax treatment in Canada.

We illustrate this below with some comparative figures for similar properties in the two countries.

CAPITAL INVESTMENTS, COST DEPLETION, SALES AND ABANDONMENTS OF PROPERTIES

Comparison of United States and Canadian Income Tax Provisions

Many of the differences between the United States and Canadian income tax effects of transactions in oil and gas properties are a consequence of the fact that capital gains and losses are taken into account for United States income tax but for Canadian income tax they are not; nor is any recovery of capital cost of property allowed in Canada except through depreciation of closely defined categories of depreciable property. Some of the main effects of this difference in principle are:

1. In the United States the cost of acquisition of an oil or gas reserve is recoverable through charges for depletion which are deducted from the income from the oil or gas produced, before taxable income arises. The same depletion of cost is allowed to the purchaser of a royalty or other continuing payment. In Canada the purchaser of an oil or gas property or of a royalty or other interest is not permitted any allowance against his income on account of his capital cost (although he may be entitled to a depletion allowance computed as a percentage of income without regard to cost of the property as explained in detail below).

Example:

(a) X, an individual, corporation, partnership or trust, buys an oil lease for $500,000. At the close of the year it is estimated to have a proven reserve of 725,000 barrels, and it has produced 25,000 barrels during the year —

In the United States — X is entitled to an allowance for depletion of his capital costs of the property and, so far as the acquisition cost is concerned, this deduction will be $\frac{25}{750} \times$ \$500,00 or \$16,666 which may be deducted against income from this property or any other income he may have. (It may be that his depletion on the property computed on a percentage basis would be more than \$16,666, in which case he would deduct percentage depletion instead.)

In Canada — X would not be entitled to any allowance against income on account of his capital cost of \$500,000 but would be entitled to an allowance (see further discussion below) based on 33⅓% of his entire production income after all deductions.

(b) X buys a one-eighth royalty in a lease, for $50,000. The lease has a proven reserve of 360,000 barrels at the close of the year and produced 40,000 barrels during the year (i.e., X received 5,000 barrels produced out of 50,000 barrels in his share of the reserve).

In the United States — X may deduct from his income $\frac{5}{50}$ ths of $50,000 or $5,000. (X would be entitled to percentage depletion in lieu of the $5,000 if the percentage depletion allowance turned out to be more than $5,000.)

In Canada — X would not be entitled to any allowance against his royalty income on account of his capital cost but would be entitled to a percentage depletion allowance of 25% of his gross income for the year from the royalty.

2. In the United States the sale of an oil or gas property, if owned more than six months and not included in inventory or held for sale to customers in the ordinary course of business, would give rise to a tax on the profit computed by subtracting from the sales proceeds the amount of the capital cost which has not been recovered through depletion allowances, but this tax would be limited to the capital gain rate of 25%. A loss on the sale of the property if it has been used in the trade or business would be deducted in full against ordinary income. On the abandonment of the property proven worthless the remaining capital cost would be deducted in full against ordinary income.

In Canada it is supposed that the profit on the sale under the same circumstances would not be subject to tax, and a loss on sale or abandonment would not be deductible to any extent — with the sole exception that the cost of a lease which has been acquired from a governmental body may be deducted when the lease is abandoned if no production has been obtained and no part of the cost has been recovered. This statement for Canada, however, has to be made bearing in mind that there is a pronounced tendency for the Department of National Revenue and the courts to take the view that properties which have been explored and developed are held for the possible purpose, among others, of making a trading profit by selling them, and that this purpose makes the profit taxable as ordinary income, while there is no indication that a loss on the sale or abandonment would be allowed as a deduction.

Summary and Comparison: The United States investor in oil or gas properties always knows that he cannot be deemed to have taxable income without having his capital cost returned to him free of tax. If he sells a property he knows that the tax on his profit will be limited to 25% thereof. On the other hand, if he has been using the property in a going business his loss on the sale thereof or, if it proves worthless, his loss on its abandonment will be allowed in full against ordinary income. These provisions tend to encourage a greater degree of risk-taking in capital investment in the United States than in Canada where there is no provision for amortizing capital cost against income, where other development and production expenses may deprive the investor of any allowance for depletion, and where the sale of a developed property may well be held to produce ordinary income while the sale at a loss or the abandonment of the investment is not reflected against income at all.

These observations apply to investments by individuals as well as by corporations. In fact, the wealthy individual investor perhaps more than the corporation in the United States would be encouraged to part with his capital, more readily than his counterpart in Canada, because of his knowledge that he can limit his tax on his profit to 25% rather than a possible 91% ordinary income tax if he sees fit to sell, while he is certain at the very least to recover his cost against ordinary income through cost depletion, or by deducting his cost against his general ordinary income if his investment proves worthless.

Exploration, Drilling and Development Costs

In Canada, expenditures for exploration and development and the cost of drilling a well would be regarded primarily as capital outlays which would not be deductible to arrive at taxable income, except for express provisions in Section 83A of the Act that drilling and exploration costs may be deducted from income. The deduction, however, is only allowed to a corporation whose principal business is production, refining or marketing of oil or natural gas, or exploring or drilling, or to an association, partnership or syndicate formed to explore or drill for petroleum or natural gas. Such an organization may deduct its drilling and exploration costs from income in the current year, or, if the current year's income is insufficient, against the income of succeeding years without limitation of time, until the costs have been fully offset against income.

In the United States, intangible drilling and the development costs of drilling wells are deductible as an expense against ordinary income whether incurred by a corporation or an individual, but expenses of exploration and development of properties, including geological and geophysical expenses, must be capitalized to the extent that they result in the acquisition or development of values which will be realized over future years; unsuccessful or abortive exploration and development expenses are written off currently. In the United States, if deductible expenditures exceed income the loss may be carried back against the income of the two previous years and forward against income of five years, as compared with Canada where exploration and drilling expenses of corporations, associations, partnerships and syndicates may be carried forward indefinitely.

Summary: The Canadian provisions for the tax-free recovery of drilling and exploration expenses are much more liberal than in the United States since in Canada all of such expenses may be deducted while in the United States a substantial part thereof must be capitalized, nor is there any time limit in Canada on the period in which they must be applied against income, provided that the expenses are incurred by a corporation whose primary business is the oil or gas business, or by an association, partnership or syndicate formed to carry on such business. In Canada, however, a corporation primarily engaged in some other business or a corporation, partnership or syndicate formed to carry on some other business, or an individual, is discouraged from venturing to invest its surplus funds in direct oil or gas exploration or drilling since its costs would largely be capital outlays with no provision for their future recovery, or at best might be classified as expenses making up a business loss which can be carried forward five years against income of the same business only.

These provisions in Canada provide a real and liberal inducement, at least for the organization whose principal business is oil or gas, to initiate exploration and drilling activities. However, if the organization has reached the stage where it has any substantial amount of production the incentive to incur further exploration and

drilling expenditures is taken away in large part by the negative effect of these expenditures on the allowance for depletion, as explained below.

The Percentage Depletion Allowance as a Deduction from Income

It has already been mentioned that there is an allowance for United States income tax purposes for the recovery of the capital cost of an oil reserve or interest therein, through deductions for depletion of the capital cost spread over the estimated life of the reserve on a unit of production basis. There is a further allowance under the United States tax law, known as percentage depletion, which is designed to provide incentive for investment and reinvestment of funds in oil and gas development. This allowance, a deduction from income, computed as 27½% of the gross income from the property, is limited, however, to 50% of the net income from the property. This is not in addition to cost depletion, but cost depletion is allowed in lieu of percentage depletion if the cost depletion allowance is greater than the allowance on the percentage basis, as may be the case where acquisition cost is high or where production expenses are high so that the "net income" is relatively low.

Under the Canadian tax law the only allowance of this kind is the allowance of 33⅓% of net production income.

The main points of difference are these — and a few examples will show their impact:

1. The United States 27½% allowance is computed on the gross income from the property, which means the value of the oil at the well-head.

2. The United States 50% allowance is computed on the net income from the particular property — i.e., the gross income less the expenses attributable to the particular property for depreciation, operating expense and overhead, development expense and so forth.

3. In either case the "property" for which the allowance is computed is, generally speaking, each separate lease. If there are two leases, one in development and the other in production, the development expenses of the former are not deducted in arriving at the net income of the latter.

4. The Canadian allowance of 33⅓% of net production profits is computed by aggregating the income and expenses for all of the taxpayer's oil and gas and other mineral resources. From the entire production revenue there must be deducted, under current regulations, (a) any losses in connection with production from *any* of his resources, (b) any deductible exploration, including geophysical and geological, and drilling expenses either for the current year or carried over to the current year from previous years of losses, and (c) interest charges on borrowed money and capital cost allowances, in connection with the exploration and production operations.

Example:

X Company has three producing leases:

	United States			
	Lease No. 1	Lease No. 2	Lease No. 3	Total
Gross Income........	$370,000	$147,000	$250,700	
Production Expense, Depreciation, Taxes and Overhead.....	58,500	87,200	43,000	
Net Income Before Depletion...	$311,500	$ 59,800	$207,700	$579,000
Depletion Allowance..	$101,750	$ 29,900	$ 68,942	$200,592
Taxable Net Income..............................				$378,408
If X Company acquired an additional, undeveloped property, Lease No. 4, and spent $442,400 in the development of such property during the year it would deduct from taxable income such $442,400 less a portion thereof required to be capitalized, say $70,000, or..				$372,400
Taxable Net Income..............................				$ 6,008

X Company's depletion allowance is undisturbed by its expenditures on Lease No. 4.

CANADA

	Lease No. 1	Lease No. 2	Lease No. 3	Total
Net Income Before Depletion.........	$311,500	$59,800	$207,700	$579,000
Depletion Allowance (33⅓% of over-all net production income)...........				$193,000
Taxable Net Income .				$386,000

If X Company spent $442,400 in the development of Lease No. 4 during the year the depletion allowance would be revised as follows:

Net Income from Leases Nos. 1, 2 and 3 before Depletion..................................	$579,000
Less Lease No. 4 expenditures..................	$442,000
Net Income before Depletion....................	$137,000
Depletion at 33⅓% of $137,000................	$ 45,666
Taxable Net Income...........................	$ 91,334

Thus, by entering into a new development venture after it has achieved a net production income, X Company reduces its depletion allowance by $147,334 from $193,000 to $45,666. While Canadian law permits X Company a more liberal exploration and drilling expense deduction than its American counterpart, X Company nevertheless has $91,334 of taxable income remaining while its American counterpart has only $6,008.

Summary and Comparison: The depletion allowance in Canada, beside giving the investor no assurance of the tax-free recovery of his capital cost, is less liberal than that in the United States under almost any conceivable circumstances. The reduction of the Canadian depletion allowance by any increase in a taxpayer's expenditures for further exploration or exploratory or developmental drilling must

necessarily have a negative influence in any company's decision whether or not to engage in such further expenditures once a production stage has been reached.

Section IV

NATIONAL ENERGY BOARD

In conclusion, we would like, as a member of the oil and gas industry, to say a word about section (c) of the terms of reference of The Royal Commission on Energy. Section (c) refers to the establishment of a National Energy Board to administer an energy policy subject to the control and authority of Parliament.

The Canadian oil and gas industry is the first to urge that the Parliament of Canada should at all times have a national energy policy and administer it in the best interests of the citizens of Canada. However while we urge that a national policy be established and administered, we question that a National Energy Board governing all forms of energy is the right way to do this. Our industry has reached its present healthy state through a system of free enterprise. We feel its continued growth will best be fostered with a minimum of intervention.

Material control of Canada's petroleum resources exists through present legislation both Dominion and Provincial. The flexibility of such legislation and its ability to march with the times has amply been demonstrated. The machinery for its administration is in being and we see no necessity for the superimposition of another bureau — indeed we feel this would be more of a hindrance than a help.

We have said already the first criterion for the Canadian oil and gas industry is the long-term interest of the Canadian consumer. We submit that such a criterion can best be ensured by the administration of the Dominion and Provincial Governments, through their existing departmental organizations and the Board of Transport Commissioners.